EXHIBIT 37

Q3 2018 Earnings Call

Company Participants

- Craig W. Collins, Vice President and Chief Operating Officer-Midstream
- Harlan H. Chappelle, President, Chief Executive Officer & Director
- James T. Hackett, Executive Chairman of the Board & Chief Operating Officer - Midstream
- Scott R. Grandt, Vice President, Finance & Investor Relations

Other Participants

- Derrick Whitfield, Analyst, Stifel, Nicolaus & Co., Inc.
- Irene Haas, Analyst, Imperial Capital LLC
- John Nelson, Analyst, Goldman Sachs & Co. LLC
- Raymond J. Deacon, Analyst, HS Energy Advisors LLC
- Sean M. Sneeden, Analyst, Guggenheim Securities LLC
- Subash Chandra, Analyst, Guggenheim Securities LLC

MANAGEMENT DISCUSSION SECTION

Operator

Good day, everyone, and welcome to the Alta Mesa Resources, LP, Third Quarter 2018 Operations Update Conference Call and Webcast. All participants will be in listen only-mode. After today's presentation, there will be an opportunity to ask questions. And please note that today's event is being recorded.

And I would now like to turn the conference over to Scott Grandt, Vice President of Finance and Investor Relations. You may please go ahead with your presentation.

Scott R. Grandt {BIO 20668019 <GO>}

Good afternoon and thank you for joining us today to discuss Alta Mesa Resources' operational and financial results for the third quarter of 2018. Joining me on today's call will be our Executive Chairman Jim Hackett; our President and Chief Executive Officer, Hal Chappelle; Kingfisher Midstream Chief Operating Officer Craig Collins; Chief Financial Officer Mike McCabe; and other members of Alta Mesa senior management.

Note that in conjunction with today's call, we have posted a slide deck on our website that we will be referencing. I'd like to remind everyone that today's discussions may contain forward looking statements and assumptions based on our

current views and reasonable expectations. However, several factors could cause actual results to differ materially from what we talk about today.

For a discussion of the risks and factors that could impact our future performance, please refer to Alta Mesa's Safe Harbor language contained in the company's annual and quarterly reports.

With that, I'll turn the call over to our Executive Chairman, Jim Hackett.

James T. Hackett {BIO 1440080 <GO>}

Thank you, Scott. I'll make some brief remarks on overall strategy before handing it off to Hal and Craig to highlight information in our detailed third quarter release. As will be discussed on this call, Alta Mesa's third quarter continued to demonstrate the growth potential of the combined Upstream and Midstream assets.

Our company has experienced significant headwinds since we were on the road show a year ago and then closing the transaction earlier this year. I continue to see some of these challenges as delays in reaching our full potential with the asset base versus structural changes to the economics of the Basin. But other technical challenges and the timing delays we've experienced are having meaningful valuation impacts on our investors.

The pace of the Upstream company's growth has trailed the original projections for volumes despite significant capital expenditures. Similarly, third-party Upstream activity levels for our Midstream customers have been slower than we expected at the time of the transaction, and especially given the recent support of price levels for liquids.

The economics of the Upstream resource base are nonetheless expected to yield future growth for Alta Mesa's Upstream and Midstream businesses. The organization remains focused on generating improved shareholder value. As we approach the Board in our upcoming meetings, we recognized that the original strategy of rapid growth and deficit spending fed by cash reserves and liquidity is not the optimal alternative in today's investor environment.

We are not committed to growth for growth's sake rather, we will focus on greater capital discipline and maintaining a pace of development and growth on the Upstream side that does not outrun our technical and commercial insights about the resource base.

On the Midstream side, we'll continue to serve the needs of Alta Mesa and other producers, while pursuing investments to expand our capabilities by adding new services such as the Cimarron Express pipeline and the formation of a produced water business.

The Board of AMR is actively engaged in evaluating our current management capabilities, execution and balance sheet. We'll share more with you after the Board deliberates on our 2019 capital and production targets in its mid-December meeting.

I now invite Hal to highlight some of the key results in today's press releases.

Harlan H. Chappelle {BIO 17883306 <GO>}

Thank you, Jim. I'll start my remarks this afternoon with a personal thank you and acknowledgement of the years of service of our CFO Mike McCabe. As highlighted in the press release today, Mike is retiring from Alta Mesa. We are grateful to have benefited from Mike's strategic vision for our company for over a decade. He was instrumental in the successful execution of the business combination and we appreciate his willingness to stay on board to help with a smooth leadership transition over the coming months.

Turning to the third quarter results, Alta Mesa delivered consolidated EBITDAX of $83.8 million on the quarter. We continue to see growth in cash flows in conjunction with the expanding operational successes we are achieving. Alta Mesa had a solid third quarter of Upstream execution of our development plan. Our production in the quarter averaged 33,400 BOE per day, greater than 30% increase over the second quarter.

Oil production in particular was up over 35% quarter-over-quarter as we work to mitigate early life well deferments, which affected our oil cut in the second quarter. Our September average production of 36,000 BOE day, represented an approximate 80% increase from the December 2017 exit rate. As a result, we are affirming our full-year production guidance to 29,000 to 31,000 BOE per day and our target 2018 exit rate of 38,000 to 40,000 BOE per day.

The strong performance quarter-over-quarter was driven by consistent execution of drilling and a steady pace of completions over the course of third quarter. As we ramp from six to now nine rigs, the execution of our field team has been remarkable. We brought 53 wells on in the third quarter. And year-to-date through November 1, we've drilled 145 wells and have brought 142 wells on line. This robust ramp in activity levels has been met with equal diligence on capital cost.

We continue to leverage improvements in drilling days (6:31) and completion times to significantly mitigate against cost pressures in the market. Over 80% of the wells we have drilled in 2018 have been on multi-well pads. The result is, we now have 30 multi-well patterns that have been online for at least 30 days, creating a growingly relevant database.

We continue to aggressively and rigorously evaluate the data and well results. We are working to optimize pad development and are optimizing our practices. For example, placement of ESPs on parent wells, reducing the total fluid volumes in infill well fracs and optimizing the order of development across multiple patterns. We're

continuing to optimize our development plans as we assess the performance of these infill wells.

We are pursuing capital efficiency through the right balance of returns and net present value per DSU. Incorporating optimized completions and artificial lift, we consider as few as five wells per DSU in the Osage and Meramec formation can maximize economic performance and recognize that there are areas where as many as 12 wells per DSU could be warranted.

Our Spacing Test began in 2014 and the more robust development process began late last year. These mold and shape our views about optimal development density. Other key factors in optimal spacing are the relative prominence of natural fractures and other rock properties in the areas being developed, the degree of isolation between stages and volumes pumped in our completions and the use of higher volume artificial lift.

Additionally, we are experiencing less production impacts where we have employed changes to our approach in managing parent wells during offset fracs. As I indicated earlier, capital efficiency is our overarching objective. One size does not fit all for this large acreage position and commodity prices are a factor.

As we rigorously evaluate the results of infill drilling and the optimization of patterns and the individual wells within those patterns, we will share additional details with you over time. Within the quarter, our Upstream operations generated operating cash flows of $60 million before working capital adjustments.

Our unhedged realized oil price of $69.67 per barrel was essentially 100% of WTI. On the operating cost side, we are experiencing some headwinds, due to the change in Oklahoma production taxes effective July 1. These drove an increase on our production taxes of about $0.93 per BOE.

The continued strengthening of crude oil prices also led to hedging loss settlements of $14 million in the quarter. When taken on net, our netback increased over 15% to $25.89 per BOE, and would have been $30.40 per BOE, excluding hedging losses. We expect to experience continued improvement in our netbacks as a large portion of our remaining 2018 hedges and virtually all our 2019 hedges are in the form of collars versus the fixed-price swaps that dominated the first three quarters of 2018. Higher production and better netback should drive revenues and we're focused on continued management of our operating expenses going forward.

We have seen well costs in the quarter modestly increase to about $3.9 million per well to drill and complete. We have continued to achieve drilling efficiencies and seek to continue to maintain our competitive capital and operating cost structure.

I'll now hand the call over to Craig to make some remarks about Kingfisher Midstream.

Craig W. Collins {BIO 20081818 <GO>}

Thanks, Hal. Turning attention to Kingfisher Midstream, we made several announcements today. First, we announced the completion of the transfer of our produced water disposal assets from Alta Mesa Upstream to Kingfisher Midstream. This transaction establishes Kingfisher Midstream as a truly full service midstream provider for producers in the STACK. With opportunities to pursue growth in each of the gas gathering and processing, crude oil gathering and transportation, and produced water gathering and disposal segments, the long-term outlook for Kingfisher Midstream is strong.

We also announced average third quarter system volumes of 116 million cubic feet per day. September volumes averaged 123 million cubic feet per day equivalent to almost one half of our operated processing capacity. We still have considerable runway, however, to continue to ramp and grow gas volumes without significant additional capital spending beyond well hook-ups, compression, and select expansion areas such as southeast Major County.

Volume ramp for Alta Mesa volumes in the plant should continue to track Alta Mesa's upstream growth going forward, while third-party volumes were up 8% quarter-over-quarter. Based on customer conversations, we expect activity levels to hold steady through the year-end before improving again in early 2019. We also remain diligent in pursuing additional third-party volumes through our ongoing business development efforts. The announced addition of a new private operator as a customer in Major County is reflective of the opportunities, we are pursuing going forward.

To reflect the totality of the shift in business development activities and the volume pace from Alta Mesa, today we also announced updated 2018 guidance for Kingfisher Midstream. We are now forecasting $36 million to $38 million of adjusted EBITDA for the business for the year, and $80 million to $90 million of capital expenditures.

Based on the results through the third quarter, this implies a fourth quarter EBITDA of $14 million to $16 million, or approximately $60 million on an annualized basis. This represents a base from which we will continue building into 2019. Continued gas volume growth from Alta Mesa and third parties to the start-up of Cimarron Express pipeline in the second half of the year, and the transfer of the produced water assets to KFM provide a positive tailwind for the Midstream EBITDA outlook going forward.

Within the guidance we indicated, we expected fourth quarter capital expenditures to be between $45 million and $55 million. This capital spending will cover off the bulk of the expenditures associated with our expansion into southeast Major County.

Alta Mesa's current activity in the fourth quarter and the recent additional dedication in the area supports this expansion project, and we expect to see volumes on the

expansion before the end of the quarter. We have provided additional detail on our full-year guidance in the third quarter materials.

I'll now turn the call back over to Hal.

Harlan H. Chappelle {BIO 17883306 <GO>}

Thanks, Craig. Looking forward to 2019 both in Upstream and Midstream, we remain focused on shareholder returns as highlighted by Jim earlier in the call. We are committed to maintaining a pace of development and growth consistent with the pace of our learnings about the resource while remaining committed to thoughtful Midstream expansion at attractive rates of return.

As we work through our 2019 planning process, we're focused on capital efficiency and long-term value creation, thus we will review with our board the range of activity levels including scenarios where we scale back our activity relative to 2018. The short cycle nature of our drilling and completions in this asset base provides significant operating flexibility to ramp activity levels up or down as we progress through 2019 based on market conditions and operational successes. We are focused on setting the base activity levels for now and being in a position to accelerate activities warranted from there.

We are also being thoughtful about deploying capital to the continued delineation of our Northwest STACK position in Southeast Major County, continuing to delineate the potential of this resource base as the focus of the rig we recently added, and we see that rig continuing to work in the area through at least the first quarter of 2019.

In conclusion, our belief is that Alta Mesa Resources represents a differentiated equity investment opportunity. We're the leading developer in the low-cost, high-return STACK oil window and our integrated business drives value creation opportunity and enhances returns.

With that, I'll now turn the call over to the operator for questions.

Q&A

Operator

Thank you. And we will now begin the question-and-answer session. And today's first questioner will be Derrick Whitfield with Stifel. Please go ahead with your question.

Q - Derrick Whitfield {BIO 17309670 <GO>}

Thanks. Good afternoon, all, and congrats on a strong Q3.

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Good afternoon, Derrick.

Q - Derrick Whitfield {BIO 17309670 <GO>}

Perhaps for Jim first, building on your opening comments, could you offer some additional color on capital spending parameters or activity levels for 2019 in your view on the urgency of achieving free cash flow neutrality based on the current environment?

A - James T. Hackett {BIO 1440080 <GO>}

Yes, I think the neutrality is going to be something we'll be wrestling with in the models we present to the board in December. I don't want to get ahead of them, Derrick. I think in Hal's comments you saw a reference to a lower activity level starting out next year. We will guide more formally to that, again, sort of towards the end of the year or first part of next year. So you'll have that relatively soon, but I don't want to get ahead of the board on that.

Q - Derrick Whitfield {BIO 17309670 <GO>}

That's fair, Jim. Thanks. And then perhaps for Hal, there's been a lot of discussion this quarter on efforts across the industry to optimize spacing for both returns and NAV and you referenced that in your comments as well. Given that you guys are fairly advanced in pattern development as shown on page 7 of the PowerPoint and based on your progress to date. Does an average density of well per section seem to be optimal for both objectives based on your position in Northeast STACK?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Thanks, Derrick. In the current commodity price environment, we expect on the order of five to seven wells per DSU for most of our 2019 infill drilling, so that's a slightly less dense that what you indicated there. In other words, we're looking at something where we could have three wells per bench in some of the applications. Our consistent growth over several years in production demonstrates the quality of the assets and the cost control we have been able to achieve allows us to have consistently profitable wells. The challenge that we and other stack operators have, as you referenced, is to find that right combination of well spacing, completions and artificial lift.

Since one size doesn't fit all and both the location of the DSU within the resource base and the commodity price environment are important, but what we're doing here is tailoring our completion, optimizing lift and coordinating execution to minimize offset well impacts in a full development mode. We find those are really the key to maximizing the value.

So that gives you a sense of that, while it can be as many as 12 wells per section, in other words four wells per bench over three benches, we really see that five to seven is a more optimal, at least in 2019.

Q - Derrick Whitfield {BIO 17309670 <GO>}

Thanks, Hal. That makes a lot of sense and I'd argue that you guys aren't getting paid for the incremental five to seven wells either. So I think a focus on returns would certainly be appreciated by the investor base.

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Thank you.

Operator

And the next question or two will be John Nelson with Goldman Sachs. Please go ahead.

Q - John Nelson {BIO 15266520 <GO>}

Good morning and – I'm sorry, good evening and thanks for the question.

A - Craig W. Collins {BIO 20081818 <GO>}

Good evening, John.

Q - John Nelson {BIO 15266520 <GO>}

You guys picked a different time. Just wanted to start out on the water drop and just hoping if you could give us a bit more details about how kind of the intersegment between each company is going to be treated. What will kind of the sourcing and disposal costs for NHB and how should we think about that CapEx level for Kingfisher going forward?

A - Craig W. Collins {BIO 20081818 <GO>}

Yeah, John, this is Craig. And I'll start with that and probably let Scott weigh in as well. But to begin with, the way we looked at this business was when we put in a long-term 15-year agreement in place in conjunction with this drop, really at a rate comparable or very similar to what has been getting allocated out previously. So the economics around the water system don't really change through this transaction. But what is important is now the assets reside in the midstream entity where the assets can be commercialized. And it's a growth platform for Kingfisher Midstream going forward.

In fact, we already are seeing a number of positive opportunities that we're progressing to build off of this drop, to secure third-party business on the system. So it's already manifesting the third-party benefits that we expected to. And it's something that we committed to in the prior quarter and we just completed it. And so we're excited to have these assets now in a position where we can go out and commercialize those.

As to the treatment around the financials, I'll defer to Scott and let him talk you through that.

A - Scott R. Grandt {BIO 20668019 <GO>}

Yeah. On a consolidated basis, so looking at AMR, you won't see a difference though because they're related parties. Just on the Upstream side, it will result in an increase to LOE on an order of magnitude of $1 to $2. It will vary because we think about that fee is charged on a dollar of water, not on a dollar of BOE incentive. There's also some benefit to – some recovery from working interest partners that goes away, which is currently another revenue line that will instead be moved into the gathering and processing revenues that you see within the Midstream business.

Q - John Nelson {BIO 15266520 <GO>}

Okay. And I think you guys had talked about roughly 10% of capital this year had been in the water business. Is that kind of a good run rate as we think about future capital?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

That's probably a little high because the 10% that we show in the slides includes spending on the freshwater segment as well which is still retained within Upstream. And so probably half of that is actually the spending on saltwater disposal.

Q - John Nelson {BIO 15266520 <GO>}

Okay. And then, I wanted to just – a housekeeping item. Is total company CapEx for 2018 kind of left unchanged from where it was originally set or I know you gave the Midstream details but wasn't sure how we should think about the Upstream?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Yeah. We've not updated the full-year Upstream guide. I would say that directionally we'd expect D&C spending in Q4 to be in line with where D&C spending was in Q3 which is a little under $200 million. We don't see as much sort of freshwater supply or that type of activity. So these – that plus the measuring guide, that gives you a pretty good proxy for your Q4 spending on CapEx.

Q - John Nelson {BIO 15266520 <GO>}

Great. I'll let somebody else hop on. Thanks.

Operator

And the next question or two will be Subash Chandra with Guggenheim. Please go ahead.

Q - Subash Chandra {BIO 1504881 <GO>}

Yeah. Thanks. Question I guess on 2019 again, and I appreciate your words of patience, I guess. But I guess from a more of a theoretical level, as you look at 2019 activity, how much of it is still understanding the development of the resource in

pattern drilling versus the sort of cash flow neutrality or desire to outspend at a lesser pace?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Subash, this is Hal. And the level of learning is certainly a continuum or the activity of learning and incorporating what we gain as we drill these wells. And where we are now is that we've developed a lot better understanding of the interaction between the wells. Where we seek additional performance data is simply in how these wells perform over a longer period of time and the role of artificial lift.

We're also seeing, Subash, that in the areas where we have more prominent natural fractures, a different performance in the infill wells such that we may be able to reduce the overall CapEx and still get the same level of recovery in those areas. And that's primarily areas to our north where you have a thicker Osage section, which in our view is a superior reservoir because we have higher oil in place, we have more prominent natural fractures, and so that's an area where we seek to learn more about that.

But clearly, when we talk about a level of activity, as Jim said that's not outrunning our learnings, that is another factor in a slightly reduced level of activity from 2018. In addition to that, the Northwest STACK area of Northern Blaine and primarily southeastern Major County is where we also have to gain a whole lot more information as we delineate that acreage.

Q - Subash Chandra {BIO 1504881 <GO>}

Okay. Thanks, Hal. And I guess as a follow-up, have you given any thought in the Osage to maybe doing a more intensive frac job which would add some expense, but do you see any benefit to that in the shape of the curve of long term recovery?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

So what we're finding in the Osage is that the role of the natural fractures is so significant that a more intense frac job to us is not necessarily measured in more cropping or more fluid. In fact, we found that less fluid is really giving a superior economics. It's really the isolation between stages and one of the things that you're pointing to is something that we intend to be testing here and either way fourth quarter or early first quarter, and that would be as many as one packer per joint, so that we could get more differentiation of the pump fluid across that natural fracturing network. So we don't lose the opportunity to connect up these natural fractures.

So more intensity, if you will, in terms of more stages. As you classify stages as an isolated section, but offset by less fluid and a moderated amount of proppant. Because what we're learning is, again, it's isolating and getting stimulation across this natural fracturing network is the most important thing in the Osage.

Q - Subash Chandra {BIO 1504881 <GO>}

Okay. Thanks. And just a final one, is there an updated timeline for Cimarron? It might be in the presentation, but just curious when you'd think it might be operational.

A - Craig W. Collins {BIO 20081818 <GO>}

Yes, Subash. This is Craig and we're still on schedule for mid-2019. The project is progressing and everything is still on track from mid-2019 in terms of having that completed and getting it started up. So that's where we're still with the project and we're building off of that to work with other producers to find opportunities to gather crude oil and get that into the pipe. We're also working closely with Blueknight who will be the operator of the pipe on those commercial opportunities. So there's a lot of attention and interest in that pipe and we're working to build off of that.

Q - Subash Chandra {BIO 1504881 <GO>}

Okay. Thanks, everybody. Congrats on getting the quarter turned around.

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Thank you, Subash.

A - James T. Hackett {BIO 1440080 <GO>}

Thanks.

Operator

And our next question or two will be Irene Haas with Imperial Capital. Please go ahead.

Q - Irene Haas {BIO 1815335 <GO>}

Yes. So I want to kind of focus on a house discussion on now that you guys have drilled more wells in sort of an infill pattern and sort of batch development, what have you learned from your 2018 wells? Are they fitting your pre-drilled type curve? And secondarily, it sounds like you're going to be drilling fewer wells per unit and I just want to know how would this impact your earlier inventory? Earlier in the year, you were talking about 14 wells per section, that would have netted you about 40 to 100 gross in roughly 1,832 net locations. How would this new spacing kind of impact your inventory?

A - James T. Hackett {BIO 1440080 <GO>}

Thanks, Irene, and good afternoon to you. Let's just – let's break that down. When we talked about the 14 wells per section, remember two of those were in Oswego acreage, where we have Oswego rights. And then the 12 wells was 4 wells per bench at 1,500-acre spacing over three benches, where we had three benches.

And we described that or we attempted to be consistent in communicating that as a proxy for the right amount of recovery within that Osage/Meramec resource, recognizing that the Osage is more prominent as we go to the north, the Meramec, more so as we go to the south in that. So just to sort of level set everybody on the call as to what the premise of that was, and what we tried to communicate was is that as a proxy for the right amount of recovery in the optimized recovery, we weren't targeting a certain number of wells as being better or worse, it was just a way of describing the recovery over that.

With that said, what we're learning here is the performance of each of these wells and this question of yours, infill wells, depends on several factors and we are continually defining how to adequately characterize that infill well performance. We expect early next year that we're going to be – having an appropriate time and we'll have enough information so that we can provide more information on infill forecasting in and of itself, if you will. And that means that, we'll likely be characterizing that, not just in terms of the zone, but also the geographic area.

As I mentioned earlier, we have areas where we have more prominent natural fracturing in this the – the mineralogy is such that we're going to think about that a little bit differently and approach it a little bit differently in terms of the number of wells that we landed in interval, the way we complete those, and the way that we live those wells. For example, with ESPs or high volume lift of jet pump.

The key factors here, again, are the prominence of natural fractures in rock properties in a specific geographic area that we're developing, the wells spacing, the completion methodology and artificial lift.

Q - Irene Haas {BIO 1815335 <GO>}

And so, how would that impact your earlier location...

A - James T. Hackett {BIO 1440080 <GO>}

Yeah.

Q - Irene Haas {BIO 1815335 <GO>}

... sounds. (32:04) I mean, granted those were early days.

A - James T. Hackett {BIO 1440080 <GO>}

Yeah. Thank you for reminding me of the rest of your question there, Irene. And, generally, when we think of an area five to seven wells per section, that's going to reduce that number of potential wells, albeit, let's recognize that we could have areas where we do have that 12 wells per DSU, depending on some of the factors I just recited a moment ago.

Q - Irene Haas {BIO 1815335 <GO>}

Okay. Well, all right. If you don't mind, may I ask one more question?

A - James T. Hackett {BIO 1440080 <GO>}

Absolutely. Please.

Q - Irene Haas {BIO 1815335 <GO>}

Yeah. So this is a general question, so you're going to make money off of produced water. And I'm wondering for this general vicinity, how much water do you actually produce along with your oil? Is this a consistent cash flow stream? That's really what I'm after.

A - James T. Hackett {BIO 1440080 <GO>}

Craig, go ahead.

A - Craig W. Collins {BIO 20081818 <GO>}

Yeah. Irene, this is Craig. And as you would expect, we see the majority of the water coming back earlier in the well life. But over the course of the well, we do expect continued water production. And so I would say it is somewhat correlated with drilling activity. But longer term, there is a lot of water that will be produced over the life of these wells. And we view it as a relatively steady cash flow going forward. It may be not as prolific as some of the other basins in the U.S., but we see – there's more water that's going to get produced out of these wells and then just what's being injected from the frac.

Q - Irene Haas {BIO 1815335 <GO>}

Yeah. So it's like – what's the ratio between oil and water, 1:1 or – just some idea?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

So typically our water-oil ratio upfront is on the order of 2:3. And then, we have about 350,000 barrels of water per well that's produced over the lifetime of that well. And most of that is the frac water. So, if that gives you a little sense, what I'm really excited about here is, if I look at this just through the upstream lens, I see a well-established saltwater disposal or produced water system with robust infrastructure that's serving a limited production of producer base albeit we have a fairly significant footprint, but one that can readily expand to provide cost effective services to our neighboring working interest partners in a lot of cases and also operators, where we don't have a working interest in those wells. And it really leverages for all the industry in this particular part of the basin, the investments that Alta Mesa has made in the past.

Q - Irene Haas {BIO 1815335 <GO>}

Okay. Great. Thank you.

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Thanks, Irene.

Operator

And the next questioner today will be Sean Sneeden with Guggenheim. Please go ahead.

A - James T. Hackett {BIO 1440080 <GO>}

Good afternoon, Sean.

Q - Sean M. Sneeden {BIO 16436245 <GO>}

Hey, good afternoon, guys. Thanks for taking the question. Hal or Mike, can you talk a little bit about your NGL marketing? I know Conway hasn't seen the level of spike as Belvieu, but can you remind us if there's an ability to ultimately reach Belvieu if you wanted to? And if so what's the costs associated with getting your NGLs to that market?

A - Craig W. Collins {BIO 20081818 <GO>}

Yeah. Sean, this is Craig again, and I'll take a stab. Jim or Hal may want to add onto this. But currently our NGLs are going to Conway. That's a legacy in conjunction with the pipeline outlet that was tied to the KFM plant when it was constructed.

And so, while those NGL barrels are going to Conway today, we're always looking for and are in active discussions to be honest with other operators that can get those barrels to Belvieu. Longer term, we want the exposure to Belvieu, the export capabilities off the water, I think, will yield superior pricing long-term at Belvieu even with the higher transport costs to get down there.

But when you look at how far ethane and propane trail at Conway relative to Belvieu, there's – that gap is more than made up by that premium at Belvieu is – more than compensates the additional transportation costs to get down there. So, we have some options with the current NGL takeaway and we're working with the current service provider as well as others with assets in the area that have access to Belvieu. And long-term, we want to get exposure to Belvieu through the NGL takeaway options that we have.

And the other objective, frankly, that we would have is to get redundancy or dual connectivity out of the plant, which is not only has value for Alta Mesa, but also for all the KFM customers. Having a single outlet is not really, where we want to be long-term. And so, getting a second connection out of the plant adds additional value on top of getting to Bellevue.

Q - Sean M. Sneeden {BIO 16436245 <GO>}

Got it. That's helpful. And when you think about trying to kind of construct that dual kind of market, would that necessitate modifying any of your existing, like, contracts with PSX or would it just be anything that you do is in addition with kind of newer volumes?

A - Craig W. Collins {BIO 20081818 <GO>}

We have some flexibility around how we would work that. I'll just put it at that. We're not necessarily tied to a long-term arrangement with them.

Q - Sean M. Sneeden {BIO 16436245 <GO>}

Fair enough. That's helpful. I guess, maybe just lastly, my gut just kind of thinking about the water sale, I guess, one, could you talk a little bit about how to think about the effect of kind of cash flow transfer from Upstream to Midstream there? And you talked a little bit about the LOE impact. But how does that kind of factor into the borrowing base? Is it just kind of through the higher LOE that the banks will run? Or how should we think about that impact fallout redetermination (39:04)?

A - James T. Hackett {BIO 1440080 <GO>}

Yes. So basically it was a current market value transaction at cash of $90 million, which was transferred from KFM to Alta Mesa Holdings. And so, that $90 million offset the stabilization of our borrowed base number of $400 million. Had we not transferred that business, it would have been closer to $500 million. So our liquidity is the same. Just we have more in cash and more available under our revolver at – Alta Mesa than we would have before.

Q - Sean M. Sneeden {BIO 16436245 <GO>}

Yeah. I got it. And so the $400 million that is kind of pro forma for the redetermination?

A - James T. Hackett {BIO 1440080 <GO>}

Yes.

Q - Sean M. Sneeden {BIO 16436245 <GO>}

Got it. Got it. That's helpful. Thank you very much.

Operator

And the next questioner today will be Ray Deacon with HS Energy Advisors. Please go ahead.

Q - Raymond J. Deacon {BIO 1736326 <GO>}

Yes. Thanks for taking my question. I was curious, Hal, with the change in thought on your development plans. Would you still stick with the type curve that has 560,000 BOEs and 250 of oil, or will that shift at all?

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Yes. Certainly the parent well performance has very – I would say, very consistently shown itself to be within that range. And so that's a pretty reliable indicator for that

initial parent well. The infill wells, we are in the process of discovering what that right number is. And most importantly is, is really not so much the EUR that's consistent with that, because that's something we have to discover as time goes by here over the next couple of months.

It's really the production profile. And so, what we've learned in 2018, and what we've seen in terms of production performance is we have a wide variation of production profiles, generally, a lower peak and really effects from the proximity to the parent the amount of offset well activity there is and the way in which we lift these wells and that's led us to saying and looking at a little looser spacing, if you will, where we are at a five- to seven-well per section development versus a 8 to 12-well, if you will.

Q - Raymond J. Deacon {BIO 1736326 <GO>}

Got it. Got it. Great. Thanks. And I guess just one more on the Midstream, if you were to look at what you have signed up on Cimarron so far and what you know about demand currently for increased water transportation services, I guess, when do you think you'd be able to give some guidance on Midstream EBITDA run rate for next year?

A - Craig W. Collins {BIO 20081818 <GO>}

Yeah. I think as a starting point, you can look fourth quarter EBITDA guide that we issued of roughly $15 million. So, as a starting point for 2019, you're at $16 million if nothing changes.

As Jim mentioned earlier in the call, we have a Board Meeting scheduled for mid-December. Full year 2019 guidance for KFM will be issued at the same time it will be issued for Alta Mesa, which will be late 2018 or early 2019. But, definitely, well before fourth quarter results are announced.

Q - Raymond J. Deacon {BIO 1736326 <GO>}

Got it. Great. Thank you.

A - Craig W. Collins {BIO 20081818 <GO>}

Thanks, Ray.

Operator

And this will conclude our question-and-answer session. I would now like to turn the conference back over to Hal Chappelle for any closing remarks.

A - Harlan H. Chappelle {BIO 17883306 <GO>}

Thank you. Again, I want to thank Mike McCabe for his service, his vision, his ingenuity for many years here that he's helped Alta Mesa become a company that it is today. I also want to thank each of you for joining us on this call. I realize as some of you noted, it is a little later in the day than we've done in the past, so thank you very much for that. It's been a really good quarter for us, one of focus and one in

which our team has demonstrated its capabilities. And we look forward to speaking with you here in the near future. Thank you.

Operator

The conference has now concluded. Thank you for attending today's presentation and you may now disconnect your line.